The Afghanistan Engineering Support Program assembled this deliverable. It is an approved, official USAID document. Budget information contained herein is for illustrative purposes. All policy, personal, financial, and procurement sensitive information has been removed. Additional information on the report can be obtained from Firouz Rooyani, Tetra Tech Sr. VP International Operations, (703) 387-2151.

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# ENGINEERING SUPPORT PROGRAM

## WO-LT-0059
## NEPS Protective Relay Coordination Studies
## Protective Relaying Coordination Criteria

May 13, 2013

*This publication was produced for review by the United States Agency for International Development. It was prepared by Tetra Tech, Inc.*

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May 13, 2013

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Re: WO-LT-0059 NEPS Protective Relay Coordination Studies

[redacted]

Enclosed is the Protective Relaying Coordination Criteria Document dated May 13, 2013. This a very technical document provided under SOW Task 7, defining protective relaying sensitivities and coordination time intervals for each major category of protection or apparatus to be reviewed for the project.

I look forward to meeting with you at your convenience to discuss this report.

Respectfully,

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# AFGHANISTAN ENGINEERING SUPPORT PROGRAM

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NEPS Protective Relay Coordination Studies
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# 1.0 Project Summary

## 1.1 Project Description

### 1.1.1 Overview

Afghanistan Engineering Support Program (AESP) is in the process of performing a coordination study of the Afghanistan Northeast Power System (NEPS) 220kV and 110kV transmission systems and 15kV distribution system. This document presents protective relaying criteria for performing the coordination study of the NEPS 220kV and 110kV transmission systems, as well as the substation feeder circuit breakers for the 10kV, 15kV and 20kV Kabul medium voltage (MV) distribution system.

The existing protective relay settings will be reviewed within the scope of the project. Where the existing system relays are found to provide unacceptable levels of protection, including any system lack of coordination (miscoordination), changes to those relay settings will be recommended if possible. In the few cases where coordination is impossible these situations will also be noted. Where the existing relay settings provide adequate protection, the settings will be recorded and changes will generally not be recommended.

An ASPEN OneLiner model of the Afghanistan NEPS 220kV and 110kV transmission systems will be constructed. This model will be used throughout the evaluation of the relay settings and will aid in identifying the validity of communication aided, step-distance, and overcurrent protective relaying schemes throughout the system. The ASPEN system model will serve as the basis for all fault current evaluation for this review.

This Protective Relaying Criteria Document reflects the state of knowledge at the time of its preparation. It is anticipated that it will be revised during the course of the project as additional information is collected and analyzed.

Protective relaying operates to isolate faulted equipment from the associated high voltage electrical system. Protective relaying enhances the overall safety and reliability of the transmission system. Using definitions from the *IEEE 100 The Authoritative Dictionary of IEEE Standards Terms – Seventh Edition,* objectives for protective relaying operation can be described as:

- *Reliability* - A combination of Dependability and Security
  - *Dependability* - The facet of reliability that relates to the degree of certainty that a relay or relay system will operate correctly.
  - *Security* – The facet of reliability that relates to the degree of certainty that a relay or relay system will not operate incorrectly.
- *Selectivity* - A general term describing the interrelated performance of relays and breakers, and other protective devices; complete selectivity being obtained when a minimum amount of equipment is removed from service for isolation of a fault or other abnormality.
- *Speed of Operation- (Also an objective*) Faster fault clearance can reduce the impact to power quality along with the potential for personal injury and damage to equipment and lines.

In plainer language, ideal protective relaying systems, including their related components (e.g. substation DC supply systems, current transformers, voltage transformers, circuit breakers, fuses and communication systems) operate to remove all faults (typically but not limited to short circuits) from the electric power system, never mis-operate, de-energize only the faulted component (e.g., lines, circuit breakers, and transformers); and do so very quickly.

In practice these goals are never perfectly met, compromises must be made between these sometimes competing goals. For example:

- *Selectivity vs. Speed* – In current and time graded overcurrent relay protection systems such as are typically used in medium voltage (MV –1001 volts through 72.5kV as defined in *IEEE 100 The Authoritative Dictionary of IEEE Standards Terms – Seventh Edition*) applications, including distribution feeder protection, tripping of source (upstream) devices must be delayed to allow protective devices nearer to the fault to operate first.
- *Selectivity vs. Sensitivity* – In current and time graded overcurrent relay protection systems such as are typically used in MV applications, including distribution feeder protection, tripping of source (upstream) devices must occur at a higher current level to allow protective devices nearer to the fault to operate first.

In addition to the result of the numerical model, engineering judgment may be applied to determine protective relaying system design and settings to mitigate conflicts similar to the selectivity vs. sensitivity scenario outlined above. The practical ability to locate faults so they can be cleared and service restored; economic and public safety considerations involved with unnecessary disruption of service; public safety considerations if faults are not cleared; accepted industry practices; ability to implement with available protective relaying systems; appropriateness for the engineering and operations staff of the operating entity; and potential for equipment damage are representative of the factors considered. These factors are generally qualitative in nature. Consequently, judgments are strongly influenced by accepted industry practice and practices of the local operating entity.

### 1.1.2 Critical Notes and Assumptions

- Where line current differential elements are available in relays, but cannot be set up securely at both ends, the line differential relay will be set to use a step-distance protection scheme with reaches similar to the associated primary/backup distance relay.
- It is assumed that current transformer wiring information will not be readily available for use in current transformer saturation calculations. Lead wire sizes and wire lengths will be approximated for saturation calculations to evaluate transformer differential elements.
- Where possible, the polarity of CT connections used for differential elements will be verified.

# 2.0 Evaluation Guidelines

## 2.1 Introduction

This section describes the guidelines by which relay settings are evaluated. Guidelines are described on a protection element basis, not on a relay basis. Some protection element guidelines apply to multiple relays (example: a guideline for transformer overcurrent backup may apply to the transformer differential relay, as well as a separate overcurrent relay).

When these guidelines cannot be met, the exception will be reported in the calculations document. Conditions where these guidelines cannot be met may include system limitations or protective device limitations.

### 2.1.1 Analysis Methodology

In general, an acceptable range of set points is defined for all overcurrent and zone distance line protection elements by a minimum, maximum, or preferred. When the existing setting falls outside of the acceptable range, a custom value will be recommended using engineering judgment.

### 2.1.2 Overcurrent Coordination Setting Guidelines

Minimum coordination time intervals (CTI) based on IEEE Std. 242-2001[4] (Table 15-2).

- Overcurrent Coordination Time Intervals
  - Between microprocessor relay inverse time elements
    - Minimum: 0.20 seconds
    - Preferred: 0.25 seconds to allow for system changes
  - Downstream fuse with upstream relay inverse time elements
    - Minimum: 0.20 seconds from fuse total clear to relay curve
    - Preferred: 0.30 seconds to allow for system changes
  - Downstream relay inverse time elements with upstream fuse
    - Minimum: 0.20 seconds
    - Preferred: 0.30 seconds to allow for system changes
- Add 0.10 seconds to all values when an electro-mechanical relay is involved, however to date the electro-mechanical relays discovered thus far are over 30 years old and unmaintained and untested for at least that duration. Therefore, all electro-mechanical relays will likely be untouched and recommended for replacement, as adjusting the settings would likely be an unproductive activity.

# 3.0 220kV and 110kV Transmission Line Protection

Zones of protection described in this section of the report are defined in Section 11.1 “Terms”.

## 3.1 Zero Sequence Compensation Settings

Verifying the relay is set using relay manufacturer’s recommended setting method.

## 3.2 Ground Directional Settings (32G)

- Where available, use the relay’s automatic ground directional settings.
- Where available, and relay capabilities allow, prioritize negative sequence voltage versus zero sequence voltage polarization.

## 3.3 Loss of Potential (LOP)

Use relay specific logic for disabling all voltage-polarized, distance elements and directional overcurrent elements when an LOP condition occurs.

## 3.4 Distance Elements (21)

Throughout initial inspection of the system, quadrilateral characteristics are used for distance protection. A criterion for the quadrilateral elements has been developed and is included in the following section. In this case, if mho elements are found upon further evaluation of the transmission system, a criterion for these elements is also included.

Where a transformer is present and connected to the remote bus, it should be treated as line with a 100% Zone 1 element if protected by a differential element. The transformer differential element will provide instantaneous tripping for the whole ‘‘impedance” of the transformer, preventing over reach of time delayed remote zone distance elements.

When available, load encroachment blocking will be set to prevent distance elements from tripping on overloads. This element will be configured so distance elements do not operate for load currents at 150% of the maximum facility rating, with 0.85 per unit rated voltage, and line phase angle of 30 degrees.

When conflicts arise and judgment must be used to make a recommendation, preference will be given to maintain security/selectivity versus sensitivity/speed.

### 3.4.1 Quadrilateral Distance Elements

- **Zone 1 Phase:**
  - Zone 1 phase element will be set without time delay in the forward direction
  - Reactive Reach
    - Minimum reach: 70% of the protected line positive-sequence reactance
    - Maximum reach: 85% of the protected line positive-sequence reactance
    - Preferred reach: 80% of the protected line positive-sequence reactance
  - Resistive Reach

        - Set to provide 2 to 5 times the reactive reach coverage. Consider a minimum of 2 times the reactive reach, and only increase if the emergency line rating is known.
    - For short lines, where relay accuracy is decreased due to high Source Impedance Ratio (SIR), reduce reactive reach values by 20%.

- **Zone 1 Ground:**
    - Zone 1 ground element will be set without time delay in the forward direction.
    - Reactive Reach
        - Minimum reach: 70% of the protected line zero-sequence impedance
        - Maximum reach: 85% of the protected line zero-sequence impedance
        - Preferred reach: 80% of the protected line zero-sequence impedance
    - Resistive Reach
        - Set to provide 2 to 5 times the reactive reach coverage.
    - For short lines, where relay accuracy is decreased due to high Source Impedance Ratio (SIR), reduce reactive reach values by 20%.

- **Zone 2 Phase:**
    - Zone 2 is typically set to reach in the forward direction, past the end of the protected line to provide fault coverage for the entire line with some margin. If a communication aided protection scheme exists, Zone 2 will provide the forward fault indication. Zone 2 should not reach past the shortest remote Zone 1 element on the next line.
    - Reactive Reach
        - Minimum reach: 120% of the protected line positive-sequence reactance
        - Maximum reach: 80% of the apparent reactance (in-feed included) of the shortest remote Zone 1 element using N-1 condition (comm. scheme out-of-service and remote terminal of remote line open)
        - Preferred reach: 100% of the protected line positive-sequence reactance, plus 50% of the longest remote transmission line positive-sequence reactance.
    - Resistive Reach
        - Set to provide 2 to 5 times the reactive reach coverage. Consider a minimum of 2 times the reactive reach, and only increase if the emergency line rating is known.
    - If utilized in a step-distance study, a time delay of 0.30 seconds will be used.
        - If the maximum reach criterion is exceeded, increase to 0.5 seconds to provide coordination with remote terminal distance elements.

- **Zone 2 Ground:**
    - Zone 2 Ground element will perform a similar function as Zone 2 Phase element.
    - Reactive Reach
        - Minimum reach: 120% of the protected line zero-sequence reactance
        - Maximum reach: 80% of the apparent reactance (in-feed included) of the shortest remote Zone 1 element using N-1 condition (comm. scheme out-of-service and remote terminal of remote line open)
        - Preferred reach: 100% of the protected line zero-sequence reactance, plus 50% of the longest remote transmission line zero-sequence reactance.
    - Resistive Reach
        - Set to provide 2 to 5 times the reactive reach coverage.
    - If utilized in a step-distance capacity, a time delay of 0.30 seconds will be used.

      - If the maximum reach criterion is exceeded, increase to 0.5 seconds to provide coordination with remote terminal distance elements.

- **Zone 3 Phase (Step-Distance or Communication-Aided):**
  - Existing elements used in the forward direction will remain in the forward direction, unless a communication aided protection requires a reverse Zone 3 element for blocking.
    - Forward Reactive Reach
      - Set to 100% of the protected transmission line positive-sequence reactance, plus 100% of the positive-sequence reactance for the longest line out of the remote terminal, including in-feed with an intact system, when used as a backup element with time delay.
    - Forward Resistive Reach
      - Set to provide 2 to 5 times the zero-sequence reactive reach coverage. Consider a minimum of 2 times the reactive reach, and only increase if the emergency line rating is known.
    - Set time delay to coordinate with the remote, forward looking, step-distance elements, and account for breaker failure timing.
      - Consider a time delay of 1.0 second.
  - Where a communication aided protection requires, Zone 3 elements may be set as a reverse element.
    - Where local Zone 3 elements overreach the remote Zone 2 element, adjustment may not be required.
    - Reverse Reactive Reach
      - Set reach to be equal to or greater than the remote line terminal Zone 2 in the reverse direction.
    - Reverse Resistive Reach
      - Set reach to be 15 to 25% greater than the remote line terminal Zone 2 reach in the reverse direction.
    - If used as a reverse element in a communication aided protection scheme, do not set a time delay.

- **Zone 3 Ground (Step-Distance or Communication-Aided):**
  - Existing elements used in the forward direction will remain in the forward direction, unless a communication aided protection requires a reverse Zone 3 element for blocking.
    - Forward Reactive Reach
      - Set to same criteria as Zone 3 Phase
    - Forward Resistive Reach
      - Set to provide 2 to 5 times the reactive reach coverage.
    - Set time delay to coordinate with the remote, forward looking, step-distance elements, and account for breaker failure timing.
      - Consider a time delay of 1.0 second.
  - Where a communication aided protection requires, Zone 3 phase and ground may be set as a reverse element.
    - Where local Zone 3 elements overreach the remote Zone 2 element, adjustment may not be required.
    - Reverse Reactive Reach
      - Set reach to be equal to or greater than the remote line terminal Zone 2 in the reverse direction.

    - Reverse Resistive Reach
        - Set reach to be 15 to 25% greater than the remote line terminal Zone 2 in the reverse direction.
    - If used as a reverse element in a communication aided protection scheme, do not set a time delay.

- **Zone 4 Phase:**
    - Use the same criteria as Zone 3 Phase
        - Set only if a reverse Zone 3 element is used in the communication aided tripping scheme and is not used for tripping.
- **Zone 4 Ground:** Use the same criteria as Zone 3 Ground
        - Set only if a reverse Zone 3 element is used in the communication aided tripping scheme and is not used for tripping.

### 3.4.2 Mho Distance Elements

While not expected, mho distance elements may be employed throughout the existing system. Mho elements will utilize the same percentage impedance reach as employed in the quadrilateral elements reactance for protective zones.

## 3.5 Communication Aided Tripping Elements

Throughout the 220kV and 110kV transmission systems, a variety of communication aided protection schemes may be used. The following sections will describe the different communication aided protection schemes with general parameters and standard settings for operation of these schemes.

Based on the initial inspection of the system, Permissive Underreaching Transfer Trip (PUTT) scheme is most commonly used. To provide consistency, use PUTT schemes throughout the system, unless individual circumstances make the use of a PUTT scheme either impractical or a poor application.

### 3.5.1 Permissive Underreaching Transfer Trip (PUTT)

The PUTT scheme will use forward looking distance elements to provide a more secure protected zone. If a Zone 1 pickup occurs at the local terminal, a permissive trip signal will be sent to the remote end terminal. If the remote terminal Zone 2 element pickups for a fault in the forward direction and receives a permissive trip from the local terminal, it will issue a trip at the remote terminal without delay.

- PUTT Trip Elements:
    - Zone 1 phase and ground distance elements
- PUTT Permissively Tripped Elements:
    - Zone 2 phase and ground distance elements
    - Directional residual ground elements can be added for additional sensitivity

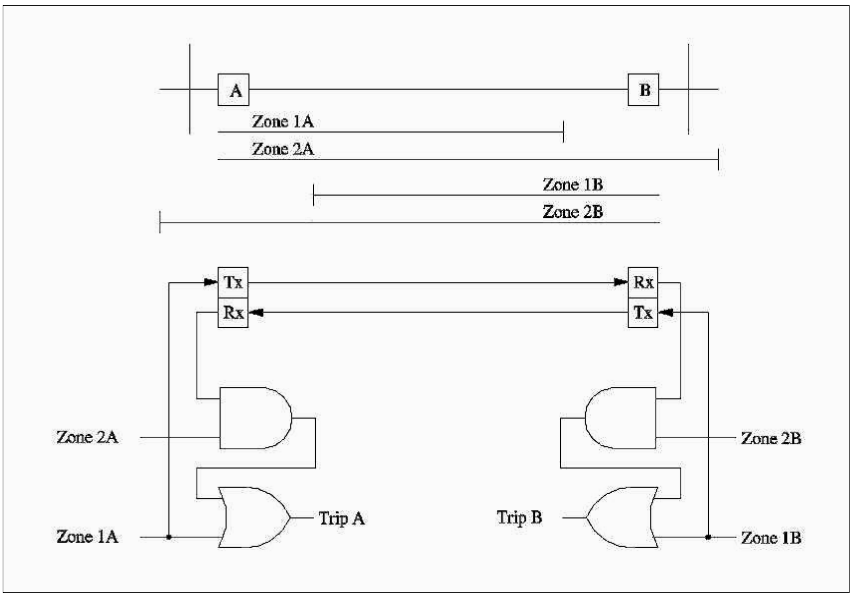


**Figure 1: PUTT Scheme Elements and Logic**

### 3.5.2 Permissive Overreaching Transfer Trip (POTT)

The POTT scheme will use forward looking distance elements to provide a more secure protected zone. If a Zone 2 pickup occurs at the local terminal, a permissive trip signal will be sent to the remote terminal. If a Zone 2 pickup at the remote terminal also occurs, a permissive signal will be sent to the local terminal. When both local and remote ends receive permissive trip signals, a trip will occur. Reverse looking blocking elements can be added for additional security.

- POTT Permissive Trip Elements:
  - Zone 2 phase and ground distance elements
  - Directional residual ground elements can be added for additional sensitivity

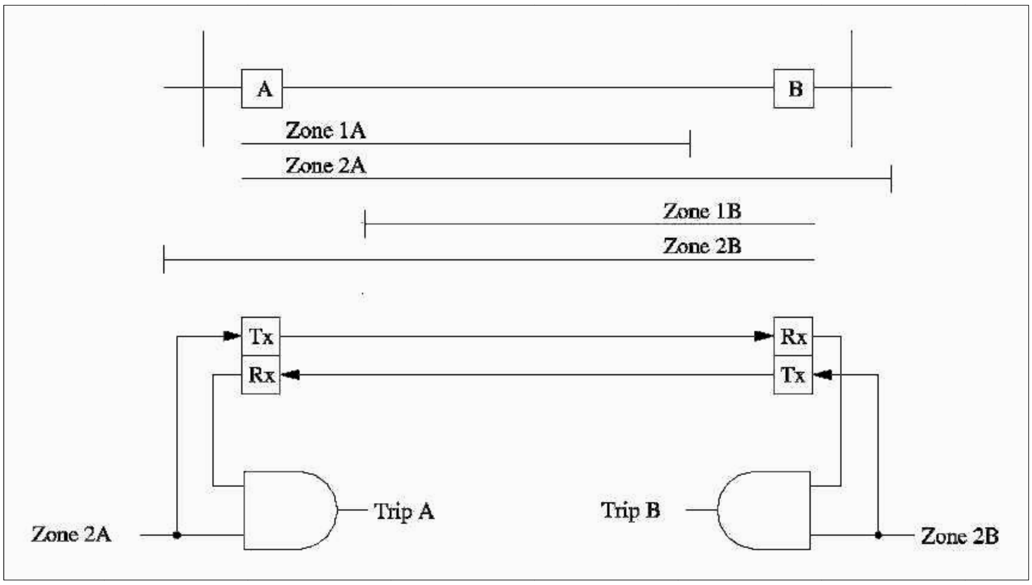


**Figure 2: POTT Scheme Elements and Logic**

### 3.5.3 Directional Comparison Blocking (DCB)

The DCB scheme will use a combination of forward and reverse elements to create the protected zone. If a reverse Zone 3 element pickup occurs, a blocking signal is sent to the remote terminal. If a forward Zone 2 element pickup occurs, and no blocking signal is received from the remote end a trip will occur.

- DCB Permissive Trip Elements:
  - Zone 2 phase and ground distance elements
  - Directional residual ground elements can be added for additional sensitivity
- DCB Guard Elements:
  - Zone 3 phase and ground distance elements
  - Directional residual ground elements can be added for additional sensitivity

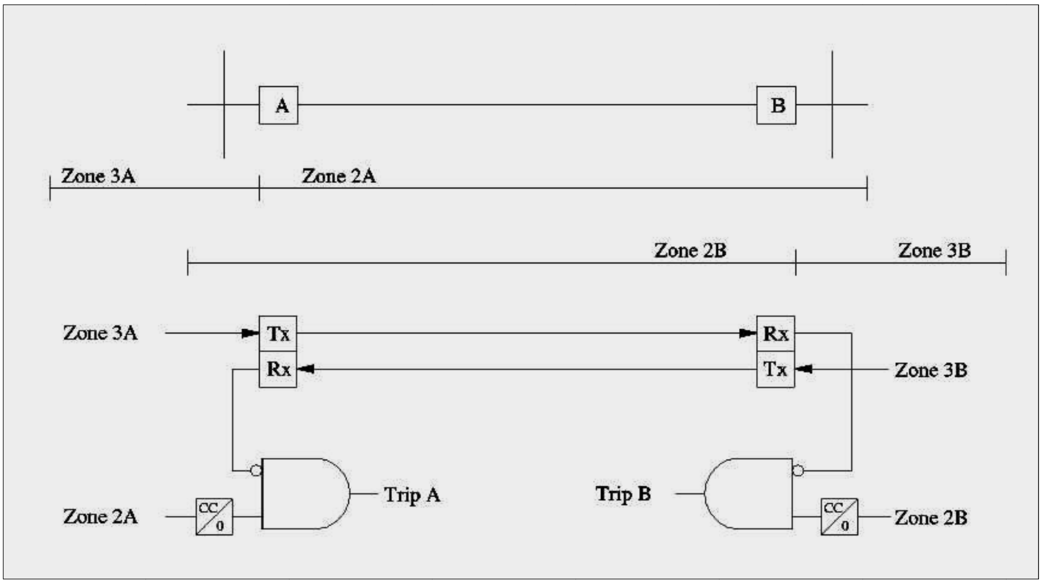


**Figure 3: DCB Scheme Elements and Logic**

## 3.6 Overvoltage Element (59)

Where overvoltage elements already exist in the system, leave the elements in place. If new overvoltage elements are added to the protective relaying, they will be set to the following criteria:

- Overvoltage Alarm
  - Element used for alarm only
  - Pickup set to 110% of nominal system voltage.
  - Time delay set to 10 seconds.
- Overvoltage Trip
  - Pickup set to 135% of nominal voltage.
  - Time delay set to 0.06 seconds

### 3.7 Power Swing Block

Where power swing blocking already exist in the system, the settings will be evaluated for being reasonable and conforming to existing practice.

- Power Swing Blocking
  - Set relay to block all zones to when it detects a power swing

### 3.8 Fault Detectors

- Zones 1 - 4 Phase:
  - Set to 50% of the minimum in-section phase-to-phase fault duty with strongest source removed.
- Zones 1 - 4 Ground:
  - Set to 50% of the minimum in-section single-line-to-ground fault duty with strongest source removed.

### 3.9 Line Overcurrent Elements

Where available, directional ground overcurrent elements will be set to be used as part of the communication aided protection, or as backup ground overcurrent protection.

- **Directional Residual Ground Instantaneous Overcurrent (67G1)**
  - Disable element in favor of Zone 1 ground distance elements.
- **Directional Residual Ground Instantaneous Overcurrent (67G2)**
  - Set pickup to a value less than the expected single line to ground fault at the end of the transmission line, and greater than an assumed system imbalance. Consider a setting of 400 A-primary.
  - This element should only be used as a forward fault indication in communication aided protection scheme to add additional security to the scheme.
- **Directional Residual Ground Instantaneous Overcurrent (67G3)**
  - Set to half the pickup of the remote terminal 67G2 element, and greater than an assumed system imbalance. Consider a setting of 200 A-primary.
  - This element should only be used as a reverse fault indication in communication aided protection scheme to add additional security to the scheme.
- **Directional Residual Ground Time Overcurrent (51G)**
  - Pick Up
    - Minimum Pickup: Verify this element is set above 10% of line rating, consider relay minimum set point for maximum sensitivity;
    - Maximum Pickup: 50% of the smallest ground fault at the remote bus, considering an N-1 contingency (where applicable).
  - Curve Type
    - Choose an IEC curve type that coordinates with other protective device curve types in the vicinity.
    - Consider a Very Inverse or Extremely Inverse curve type.
  - Time Dial
    - Choose a time dial that meets CTI requirements mentioned in the Overcurrent Coordination Setting Guideline section.

- Round all time dial to the nearest ½ (x.0 or x.5). Be sure to recheck coordination after making time dial changes.

### 3.10 Switch-on-to-Fault (where available)

- Generally recommended for all lines, especially with CCVT type voltage transformer applied on the line side of the breaker.
  - Used for instantaneous tripping following the closing of a breaker onto a faulted line.
- Phase Instantaneous Overcurrent (50P)
  - Maximum setting: 100% of smallest mid-line fault current
  - Preferred setting: 50% of smallest mid-line fault current
  - Configure this element to be active for 8-12 cycles following the closing of the breaker.

### 3.11 Line Differential Protection Guidelines (87L)

- Line Current Differential Element
  - If one of the terminals is not set up to handle line current differential protection, the differential element will be disabled.
  - Where line current differential elements are available, the following criteria will be followed.
    - Consider the relay manufacturer recommended settings.
    - Set the current differential pickup in the range of 0.2 per unit to 0.5 per unit.
    - Set sensitive slope to detect low current magnitude faults:
      - CT Error (10%)
      - Relay Error (5%)
    - Set the break point between sensitive slope and high-stability slope below the current at which the CTs are expected to go into DC saturation.
    - Set high-sensitivity slope to provide secure operation during high-current through-faults.

# 4.0 Transformer Protection Guidelines

## 4.1 Differential Elements (87)

- Set differential pickup to avoid false tripping for system imbalance.
- Sensitive Slope
  - Set sensitive slope (ratio of restraint current and operation current) to detect low current magnitude faults.
    - Avoid setting too sensitively and avoid tripping due to:
      - CT errors (5%)
      - Relay Error (5%)
      - Transformer Exciting Current (3%)
      - Load Tap Changer Induced Error (if applicable)
      - De-energized Tap Changer Induced Error (if applicable)
- High-Stability Slope
  - Set high-stability slope (ratio of restraint current and operation current) to provide security for through faults currents.
    - Avoid setting too sensitively and avoid tripping due to:
      - Expected CT Saturation Error
      - Transformer Exciting Current (3%)
      - Relay Error (5%)
      - Load Tap Changer Induced Error (if applicable)
      - De-energized Tap Changer Induced Error (if applicable)
  - Set the pickup to change between the sensitive slope and the high stability slope to the relay manufacturer recommendation.
    - Verify this pickup is set low enough for the change to occur before CTs go into saturation.
  - Unrestrained Differential Element
    - Verify pickup is greater than transformer inrush (estimated at 12 times the transformer base rating) and through-fault current
    - Verify this pickup is less than the minimum high-side fault duty
  - Harmonic Restraint or Blocking (where available in a relay)
    - Harmonic restraint is preferred over blocking when available.
    - Enable harmonic restraint/blocking for inrush current ($2^{nd}$ and $4^{th}$ Harmonics).
    - Enable harmonic restraint/blocking for transformer over excitation ($5^{th}$ Harmonic).

## 4.2 Restricted Earth Fault (REF)

- Restricted Earth Fault elements will be utilized where the function is already in service in the protective relay.
  - Compares the direction of neutral and winding residual current for more rapid and sensitive ground fault detection in grounded-wye windings.
- Set residual current pickup to 20% of full transformer rating to account for system imbalance.
- If available in the relay, prevent operation when CT saturation is detected.

## 4.3 Overcurrent Elements (50/51)

- **High-Side Phase Instantaneous Overcurrent (50P)**

- Set to the greatest of 125% of the maximum 3-phase through-fault or 100% of inrush.
  - Inrush will be defined as 12 times the transformer base rating for 0.1 seconds

- **High-Side Phase Time Overcurrent (51P)**
  - Pickup
    - Minimum pickup: 125% of expected emergency loading. When the actual emergency loading is not known, the transformer maximum rating is used.
    - Maximum pickup: 200% of transformer maximum rating
  - Curve Type
    - Choose an IEC curve type that coordinates with other protective device curve types in the vicinity.
    - Consider a Very Inverse or Extremely Inverse curve type.
  - Time Dial
    - Choose a time dial that meets the minimum CTI requirements mentioned in Section 2.1.2.
    - Round all time dial to the nearest ½ (x.0 or x.5). Be sure to recheck coordination after making time dial changes.

- **Neutral Time Overcurrent (51N)**
  - Neutral time overcurrent elements will be utilized when relay current is provided from a current transformer located in a solidly grounded, wye neutral connection.
  - Pickup
    - Minimum Pickup: Verify pickup allows for at least 30% unbalance, consider relay minimum set point for maximum sensitivity
    - Maximum Pickup: 30% of the smallest ground fault at the remote bus, considering an N-1 contingency (where applicable).
  - Curve Type
    - Choose an IEC curve type that coordinates with other protective device curve types in the vicinity.
    - Consider a Very Inverse or Extremely Inverse curve type.
  - Time Dial
    - Choose a time dial that meets the minimum CTI requirements listed above.
    - Round all time dial to the nearest ½ (x.0 or x.5). Be sure to recheck coordination after making time dial changes.

# 5.0 Bus Protection Guidelines

## 5.1 Low Impedance Bus Differential (87B)

- Pickup
  - Set pickup to 1.0 per unit current to avoid tripping on load current when one CT is shorted out or 50% of the minimum fault current contribution, whichever is less.
    - This setting is chosen based on the maximum magnitude of the differential current that might be seen under normal operating conditions.
    - Verify that the pickup setting is secure for through-faults on any auxiliary transformers in the differential zone.
- Sensitive Slope Setting
  - Set sensitive slope (ratio of restraint current and operation current) to detect low current magnitude faults.
    - Set to be secure for:
      - CT Error (5%)
      - Relay Error (5%)
- High-Stability Slope Setting
  - Set high-stability slope (ratio of restraint current and operation current) to provide security for through faults currents.
    - Set to be secure for:
      - Expected CT Saturation Error
      - Relay Error (5%)
  - Provide secure relay operation for through-faults.
- Break Point (if multi-slope relay)
  - Set the break point between the sensitive and high-stability slopes to a value that is below the minimum AC current that is likely to saturate the weakest CT feeding the relay.

## 5.2 High Impedance Bus Differential (87Z)

Refer to relay manufacturer recommendations, where available, to guide in the evaluation of the relay settings.

- Minimum set point: Set to 150% of the voltage generated at the relay terminals during an out of zone fault.
- Maximum set point: 200% of the current transformers C rating.
- Preferred set point: Set to 200% of the voltage generated at the relay terminals during an out of zone fault.

## 6.0 Capacitor Bank Protection

Capacitor bank protection will be evaluated on a case by case basis for each station. Evaluation may include review of voltage differential elements, definite time overcurrent neutral elements, neutral time overcurrent elements, or residual ground time overcurrent elements.

- Definite Time Overcurrent (50P)
  - Set phase instantaneous trip to 5 times capacitor full-load amps.
  - Set trip delay to 0.05 seconds
- Time Overcurrent (51P)
  - Pickup
    - Set minimum pickup to approximately 150% of capacitor bank full-load amps.
  - Curve Type
    - Choose an IEC curve type that coordinates with other protective device curve types in the vicinity.
    - Consider a Very Inverse or Extremely Inverse curve type.
  - Time Dial
    - Choose a time dial that meets the minimum CTI requirements mentioned in the Overcurrent Coordination Setting Guideline section.
    - Round all time dial to the nearest ½ (x.0 or x.5). Be sure to recheck coordination after making time dial changes.
    - Verify that element coordinates with capacitor bank fuses.
- Neutral Overvoltage Protection (59N)
  - If the capability exists to provide neutral overvoltage protection, use the following criteria
  - Determine the number of cans that must fail in order to produce a single can overvoltage of 110% (of rating, not nominal).
    - Determine the neutral voltage produced by this number of failed cans
    - Determine the neutral voltage produced by one less failed can
    - Set the pickup to halfway between the preceding two numbers
  - Set time delay to coordinate system ground element pickup time for a close-in fault with at least 0.30 seconds of margin.
- If other protective relaying principles are implemented evaluate and develop settings on a case by case basis.

# 7.0 Breaker Protection and Control Guidelines

## 7.1 Breaker Failure (50BF)

In the absence of a transmission line critical fault clearing time, use the following criteria for breaker failure applications.

### 7.1.1 Breaker Failure Current Detector

Depending on the relay manufacturer, a phase current detector, or a phase and ground current detector may be available for use in breaker failure applications.

- Breaker Failure Load Detector (Phase)
  - Set to minimum value to detect load current.
  - Preferred pickup: 0.20 per unit
- Breaker Failure Load Detector (Neutral)
  - Set to provide coverage for resistive faults.
  - Preferred pickup: 0.20 per unit

### 7.1.2 Breaker Failure Timing

- Set breaker failure time delay no lower than the sum of the following:
  - Twice the maximum breaker operating/interrupting time.
    - Where breaker interrupting time is not known, use 0.08 seconds.
  - 0.02 seconds for current detector dropout
  - 0.02 seconds for safety margin

## 7.2 Reclosing (79)

Where reclosing is already in place, use the following criteria to employ the function. Reclosing will be investigated for transmission line terminals only.

- Implement one shot high-speed reclose only
  - Where reclosing is not used, verify if existing protective relaying system allows for this functionality to be implemented.
- Initiate reclosing for:
  - Any protection element trip in the communication aided protection or line differential relays
- Block reclosing for:
  - Breaker failure trip, an out of zone fault, a ground time overcurrent element trip, or trips while LOP condition exists.
- Reclosing Supervision
  - Dead Line-Live Bus
  - Live Line-Live Bus with Synchronism checking supervision
- Reclosing Time Delay
  - Where reclosing is already employed, consider using the existing setting unless specific circumstances dictate to the contrary
  - Do not set reclosing open interval timer to less than 0.5 second
- Do not apply reclosing when the line under consideration:
  - Terminates on the same bus as generation

- Terminates on a bus separated only by one line from the generator
- Could be connected radially to a generator by reconfiguring the switching of the transmission system.

### 7.3 Synchronism Checking (25)

Where synchronism is already in place, consider using the existing settings. Where deviating from the existing settings, use the following criteria to employ the function.

- Synch-check set points for the applicable breaker will be set as follows:
  - Voltage threshold is 85% to 115% of the nominal voltage
  - Maximum angle difference set to 40 degrees.
  - Maximum slip frequency set to 0.10 Hz.
  - Where generation is close-by, do not set higher than 10 degrees for angle difference.

### 7.4 Voltage Supervision Setting Guidelines

- Typical live and dead conditions are defined as follows:
  - Live – Measured voltage greater than 75% of nominal
  - Dead – Measured voltage less than 25% of nominal.

# 8.0 Distribution Feeder Protection

## 8.1 Distribution System Considerations

- The distribution protection for this project presents a non-typical challenge in that preliminary data collection has exposed that many transformers do not have primary (10 kV, 15 kV, or 20 kV) fuses. A piece of small diameter conductor is connected across the fuse holder in place of a fuse. Because of the lack of transformer fuses the usual level of selectivity cannot be obtained, nor can the usual level of sensitivity for internal transformer faults (usually sort circuits) be obtained. If a fault occurs within a transformer it may be necessary to remove the entire feeder from service to de-energize a fault in an individual transformer. More typically, with properly sized fuses and coordinating feeder relays, a fault within a transformer would result in one or more fuses operating, de-energizing the faulted transformer and clearing the fault without opening the circuit breaker. Electric service disruption would be limited to those served by the faulted transformer.
- The protective relaying criteria for 10, 15, and 20 kV distribution feeder circuit protective relaying will establish the framework for developing a number standardized protective relay settings which will be used across the system. The standardization will simplify protective relay setting and testing as well as improve reliability by providing more consistent and predictable protective relay operation.
- Individual feeder characteristics will be reviewed and feeders will be classified (e.g. Heavy Loaded 20 kV feeder, Lightly Loaded 20 kV feeder, and so on) into a limited number of classifications. The factors which will constrain the feeder relay settings will be established for each feeder classification. Some of the constraining factors can be determined with accuracy while others, due to lack of practically available information, will be estimated based upon existing relay settings coupled with a general knowledge of the distribution system and engineering judgment.
- A discussion of constraining factors follows:
  - Voltage, Substation Transformer Connection, and Substation Transformer Neutral Grounding – This information will be available on substation drawings and existing inspection reports and will be confirmed by field observation.
  - Distribution Feeder Circuit Breaker Continuous Current Rating – This information will be available on substation drawings and existing inspection reports and will be confirmed by field observation.
  - Available Short Circuit Current – Available short circuit current can be estimated with good accuracy based upon the substation transformer impedances and transmission/generation system information developed in previous studies.
  - Source Side Protective Relay Settings – Source side protective relay settings will be determined as part of the coordination study and will be selected to coordinate with the feeder relay settings.
  - Distribution Feeder Substation Get-Away Conductor/Cable Sizes – Field observations and in some cases substation drawings will allow estimating sizes. To determine sizes with certainty would require de-energizing the feeder to allow close-up inspection and measurement of the conductor or cable.
  - Maximum Load Current Per Phase – Based on data gathering performed to date of this writing, this information is not expected to be available. For purposes of

protective relay setting this information will be estimated from existing relay settings and substation get-away conductor/cable size.

- Load Side Protective Devices – Based upon initial data collection reports the feeder circuit breaker protects all of the overhead line, there are no in line fuses or automatic circuit reclosers to sectionalize the line. Distribution transformers then become the load side device that the feeder circuit breaker protective relaying should coordinate with. As noted previously, preliminary inspection reports also have exposed that many distribution transformers have had their high voltage fuses replaced with small diameter wire. Without transformer fuses the feeder circuit breaker must operate for distribution transformer faults, and the time-current coordination that normally exists to allow transformer fuses to operate before the feeder circuit breaker cannot exist.
- Manner of Connecting Load Serving Transformers to the Distribution Feeder – Based upon our understanding of electric utility practice in Afghanistan load serving transformers will be three phase, delta primary with wye connected secondaries. Typical secondary (consumption) voltages are 400 volt phase to phase and 230 volt phase to neutral.

○ These guidelines may be subject to revision as more complete data becomes available. They have been prepared based upon limited knowledge of the existing system as complete field collected data was not available at the time of this writing.

## 8.2 Distribution Overcurrent Protection

It may not be possible to meet all guidelines. If all guidelines cannot be met it will be noted and an explanation will be provided.

○ **Largest Load Side Fuse (10kV)**

- This section will be developed when field data collection information becomes available.

○ **Largest Load Side Fuse (15kV)**

- The 15kV feeder relays will be set to coordinate with fusing for an 800 kVA transformer. Because existing fuse sizes are unknown, fuse characteristic will be developed by looking at a variety of fuse types (e.g. T links, K links, E standard power fuses and E slow power fuses). A composite curve will be developed that will allow coordination with any of these commonly used fuse types. If actual field data becomes available it will be added to the composite curve. If practical, 1000 kVA fusing characteristics will be used above a few hundred amps to minimize likelihood of miscoordination for the few 15kV 1000 kVA transformers on the system.
- For 1000 kVA transformers, coordination will not be assured between the feeder breaker and transformer fuses. This decision is driven by engineering judgment that the best protective relaying compromise is to retain the lower ground relay pick-up needed for 800 kVA transformer fusing to increase the likelihood of downed phase conductors being detected and cleared by the feeder relay over the limited risk of miscoordination for a few 1000 kVA transformers.

○ **Largest Load Side Fuse (20kV)**

- The 20kV feeder relays will be set to coordinate with fusing for a 1000 kVA transformer. Because existing fuse sizes are unknown, fuse characteristic will be developed by looking at a variety of fuse types (e.g. T links, K links, E standard power fuses and E slow power fuses,). A composite curve will be developed that will allow coordination with any of these commonly used fuse types. If actual field data becomes available it will be added to the composite curve.

- The reduced current at 20kV results in 1000 kVA transformer fuses at 20kV being less than or equal to in size to 800 kVA transformer fuses at 15kV

- **<u>Phase Over Current Instantaneous (50)</u>**
  - If reclosing is used set to a value of current approximately equal to but greater than the current at 0.04 seconds (two cycles at 50 Hz) total clearing time for the largest load side fuse.
  - If reclosing is not used this element will not be used to avoid simultaneous operation of the fuse and the feeder breaker.

- **<u>High Set Phase Over Current Definite Time (50DT - HI)</u>**
  - If reclosing is used set to a value of current approximately equal to but greater than the current at 0.2 seconds total clearing time for the largest load side fuse. Set time delay to 0.2 seconds.
  - Without reclosing add the CTI from elsewhere in this criteria document to the time delay.

- **<u>Low Set Phase Over Current Definite Time (50DT – LO)</u>**
  - Pick-up value will be selected, to the extent possible:
    - At least 50% above maximum expected load current. This will allow for temporary overloads when energizing the feeder after a prolonged outage (cold load pick-up).
    - No more than 25% above estimated continuous current rating of substation get-away conductor or cable calculated at 10C ambient and 75C conductor temperature, .61 m/s cross-wind. This will allow for temporary overloads when energizing the feeder after a prolonged outage (cold load pick-up) while minimizing opportunity for conductor damage due to sustained overloads. This setting will favor reliability of service rather than protection of conductor to long term overloading. Feeder loading should be monitored at peak loading periods, and if conductor overloading is occurring, changes should be made to the distribution system to alleviate the overloading.
    - No more than the projected line to line fault current, calculated with a 10 Ω primary fault resistance, at the end of the line section protected by the feeder relay. Representative values for available short circuit current at the substation, feeder conductor size and type, structure geometry and distance to first protective device will be used for this calculation.
    - No more than feeder circuit breaker continuous current rating.
  - With reclosing exceed and approximately match time delay to the total clearing time for the largest load side fuse.
  - Without reclosing add the CTI from elsewhere in this criteria document to the time delay.

- **<u>Phase Over Current Inverse Time (51)</u>**
  - To match existing practice this element will not be used.

- **Ground Over Current Instantaneous (50G)**
  - This element will not be used. It can easily result in miscoordination with load side protection devices unless set at or above the 50 element. Setting it would only duplicate the 50 element functionality and add unnecessary complexity.
- **High Set Ground Over Current Definite Time (50GDT - HI)**
  - If reclosing is used set approximately equal to but great than the current at the 4.0 seconds total clearing time for the largest load side fuse. Set time delay to 4.0 seconds.
  - Without reclosing add the CTI from elsewhere in this criteria document to the time delay.
- **Low Set Ground Over Current Definite Time (50GDT – LO)**
  - If reclosing is used set approximately equal to but greater than the value of current at the 30 second total clearing time for the largest load side fuse. Set time delay to 30 seconds.
  - Without reclosing add the CTI from elsewhere in this criteria document to the time delay.
- **Ground Over Current Inverse Time (51G)**
  - To match existing practice this element will not be used.
- **Reclosing Sequence**
  - One reclose after a three second time delay will be the default reclosing setting. This reclosing sequence may be reevaluated based upon existing relay settings.
  - Preliminary data acquisition indicates that some substations do not have reclosing capability. Settings will be adjusted to for these stations to avoid simultaneous operation of the circuit breaker and the largest load-side fuse as described in previous sections.
  - Often two or even three reclose attempts are included on distribution circuits. However given the relative absence of trees and therefore the lower likelihood of tree limb related outages coupled with the relatively poor condition of the distribution system (which is expected to result in a higher proportion of permanent faults) the benefits of additional recloses to reliability is reduced. Reducing the number of recloses to one will reduce opportunities for injury due to contact with downed but still energized distribution conductors.

## 9.0 Distribution Bus Main Breaker Protection

- **Reclosing**
  - No reclosing will be used
- **Instantaneous Elements**
  - 50 and 50G elements will not be used to avoid miscoordination with downstream devices
- **Ground Elements**
  - Stepped 50G DT-LO and 50 G DT-HI curves are preferred but 51G IDMT (Inverse Definite Minimum Time) curves can be used at the discretion of the engineer
  - Minimum pick-up approximately 10% greater than the highest 50G DT-LO setting used on the load side feeders.
  - The minimum CTI established elsewhere in this criteria document between source side and load side protective relay time current curves, including adjustment for changes in magnitude of line to line and phase to ground fault currents through the substation delta-wye connected transformer.
  - Set relay elements to favor sensitivity and speed. Because of delta connected three phase distribution transformers there will be no steady state ground current.
- **Phase Elements**
  - Stepped 50 DT-LO and 50 DT-HI curves are preferred but 51 IDMT (Inverse Definite Minimum Time) curves can be used at the discretion of the engineer
  - Minimum pick-up equal to lesser of: 1) approximately 125% of transformer maximum MVA rating at rated voltage or 2) breaker continuous rating.
  - The minimum CTI established elsewhere in this criteria document between source side and load side protective relay time current curves, including adjustment for changes in magnitude of line to line and phase to ground fault current through the substation delta-wye connected transformer.
  - Set relay elements to favor load carrying capability and security. This relay must allow maximum load current to be provided by the transformer.

# 10.0 Aspen Overcurrent Coordination Checking

The following is a generalized approach to verifying overcurrent coordination using Aspen OneLiner's built-in functionality, for reference only. Refer to software manufacturer documentation for instruction related to using the "Check Primary/Backup Coordination" tool.

Coordination between 51G curves is analyzed using Aspen OneLiner's "Check Primary/Backup Coordination". The following is a sample screen shot of the tool's interface and text from Aspen's help menu describing how the checking works.

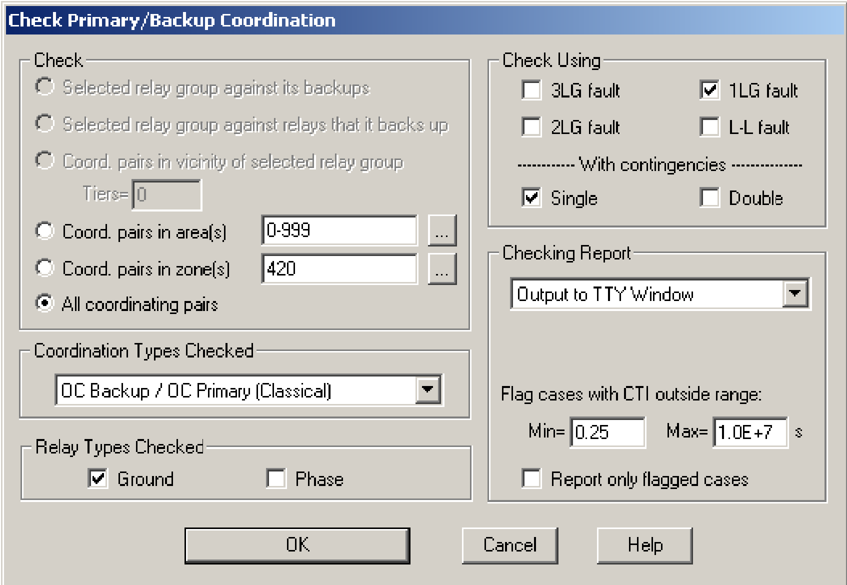


**Figure 4: Aspen OneLiner Coordination Check**

## 10.1 ASPEN Classical OC/OC Coordination Checking Algorithm:

One of the two methods for checking overcurrent/overcurrent relay coordination is labeled "Classical." The method is so called because it has been in used in the industry for years, and it was the only method available in *OneLiner* prior to version 9. The classical method works as follows:

- A close-in fault of the type selected is applied to the primary relay group with the remote end of the branch open. This condition usually generates the highest relay current in the primary relay group. The relay operating time of the relays in the primary relay group is checked. If there is no instantaneous operation or if the primary relay is on a transformer, set the scaling factor to 1.0 and go to Step 3.
- Compute the scaling factor Inst/I, where I is the relay current of the relay that operated instantaneously and Inst is the instantaneous setting of that relay.
- Multiply the primary and backup relay currents by the scaling factor. This effectively simulates an intermediate fault in front of the primary relay in which the primary relay current is just below the instantaneous value.

    - This method is exact if the primary relay is on a transmission line that is not mutually coupled. The results are approximate if the line is mutually coupled.
- Compute the relay operating times.

The above steps are repeated with no outages and then, if selected, with single and double outages of branches that are connected to the primary bus.

## 10.2 Multi-Point Coordination Checking Algorithm:

In contrast to the "classical" method, which checks the primary/backup coordination for a single fault, the multi-point method checks the coordination for a large number of faults along the primary branch, with the remote end of the branch open and closed. Specifically, the multi-point method works like this:

- The program simulates the following faults on the branch where the primary relay group is located:
    - Close-in faults in front of the primary relay group, with the remote end of the branch closed and opened.
    - If the primary group is on a line, intermediate faults on every 10%, with the remote end of the line closed and opened.
    - Line-end faults
    - Remote bus faults
- In each of faults simulated, the program calculates the operating time of selected relays in the primary and backup groups. The program then calculates the CTI.
- Depending on the selected report option the program will report the checking result for every fault, or only for faults that result in CTI violations.
- If the contingency options are tuned on, Steps 1 through 3 are repeated with single and/or double outages of branches that are adjacent to the primary relay group.

# 11.0 Definitions and References

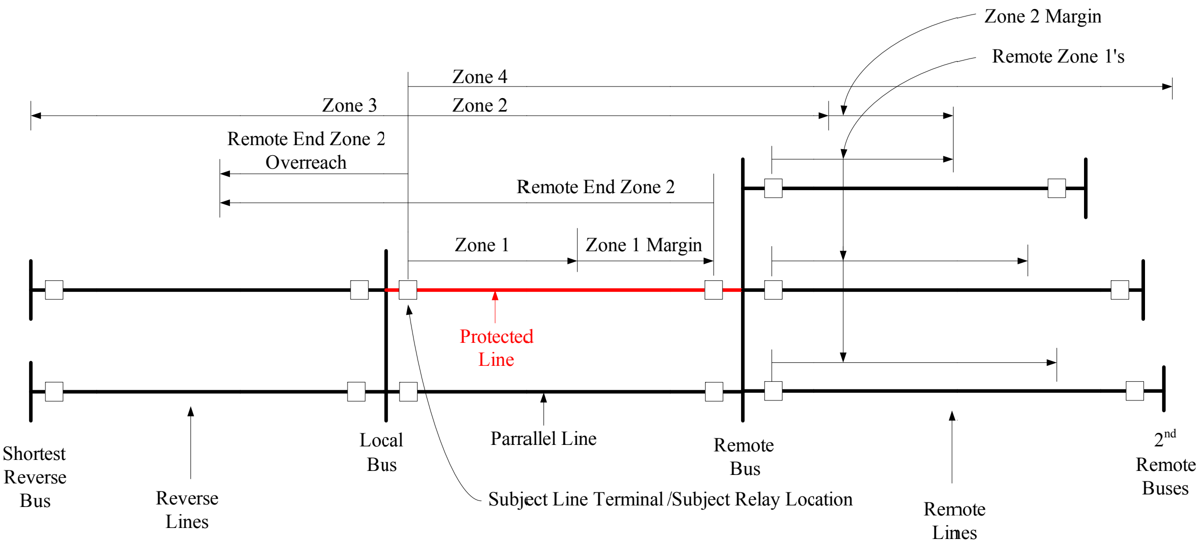


**Figure 5: Zones of Protection**

## 11.1 Terms

The technical terms used in these guidelines generally comply with industry, and more specifically, IEEE usage. Definitions of a few terms that may benefit from clarification of their specific use in this report are included later in this section.

Coordination Time Interval (CTI) – The preferred minimum difference, expressed in seconds or cycles at power frequency, between the time current characteristics or two overcurrent protective devices (typically fuses , circuit breakers or automatic circuit reclosers) to allow for selective tripping between the two devices.

Intact system – Electric transmission system in its normal operating configuration (i.e. all normally closed CBs and switches closed, all normally open CBs and switches open, and normal generation on line)

Load Terminal – A connection to a transmission line or substation that is not a source of fault current

Local or Local Bus – Usually used to refer to the station where the relays being considered are located

Distance – Usually refers to the electrical distance (impedance) between points on the electrical system instead of the physical distance.

Remaining source – Used to refer to those source terminals connected to the transmission line or bus that remain connected and supplying fault current for the case under consideration. In a typical contingency case this would be all source terminals less the faulted line and the source removed to investigate system performance under contingency conditions.

Remote end – Refers to a terminal of the transmission line remote from the relay of interest.

Second Bus or 2nd Remote Bus – A bus separated by one transmission line from the remote end bus. Zone 3 distance relays are usually set to reach past the second bus to provide remote backup protection for CB failure or DC battery failure at the remote bus.

Source Terminal – A connection to a transmission line or substation that is a source of fault current.

Three-terminal line – A transmission line that has three source terminals. It may have load terminals in addition.

Two-terminal line – A transmission line that has two source terminals. It may have load terminals in addition.

Zone 1 – Subject relay instantaneous zone

Zone 2 – Subject relay overreaching, time delayed zone

Zone 3 – Subject relay reverse reaching zone, used in Pilot schemes

Zone 4 – Subject relay long reaching, long time delayed zone

- Sometimes called Zone 3 if no Pilot scheme is used

Remote Bus – The bus at the opposite end of the protected line

Remote Lines – Lines connected to remote bus

Remote Zone 1, Zone 2, etc. – Forward reaching zones of the remote lines

Remote End Zone 2 – The zone 2 element at the opposite end of the protected line that is looking back at the subject line terminal

- Remote Zone 2 is different from Remote End Zone 2

Reverse lines – Lines connected to the same bus at the protected line

- Note that a parallel line is both a remote line and a reverse line

Reverse Bus – Bus at the end of the reverse lines

Remote End Zone 2 overreach - The amount the remote end Zone 2 reaches behind the subject relay terminal

Margin – The area between the ends of a local zone and some zone you are trying to over/under reach

- Zone 2 margin is the area between "Zone 2" and the "Remote Zone 2"
- Zone 3 Margin is the area between "Zone 3" and the "Remote End Zone 2"

## 11.2 Discussion of Primary and Backup Protection

The terms primary and backup protection, as used in the industry, sometimes appear to have ambiguous meaning. Within this report the distinction between primary and backup is based upon whether a relay element is expected to operate for a fault, and is independent of whether the element is in a relay labeled "primary" or "backup".

Primary protective relaying elements are those that are expected to trip for a fault in the protected equipment. The targets observed after a fault are expected to include all or a portion of the primary elements. The elements that actually operate will vary depending upon the type, magnitude, and location of the fault.

Backup protective relay elements are those that are delayed in time, have reduced sensitivity, or for other reasons are not expected to operate *so long as the primary protective relaying elements operate properly*.

Some elements do not fit clearly into one definition or another and these elements are listed as backup.

A couple of consequences of these definitions are:

- Tripping of a backup element during a fault may indicate that there is a problem with the protective relaying, and should be investigated.
- Primary protective relaying elements may reside in two or more protective relays, and likewise backup protective relaying elements may reside in two or more relays.

## 11.3 Abbreviations

### 11.3.1 Protective Elements and IEEE Numbers

| | |
|---|---|
| 21P | Phase distance |
| 21G | Ground distance |
| 50P | Phase instantaneous overcurrent |
| 50PDT | Phase Definite-time Overcurrent |
| 50G | Residual ground instantaneous overcurrent |
| 50GDT | Residual ground definite-time overcurrent |
| 50N | Neutral ground instantaneous overcurrent |
| 50NDT | Neutral ground definite-time overcurrent |
| 50BF | 50 element used as fault detector in a breaker failure protection scheme |
| 51G | Residual ground inverse time overcurrent |
| 51N | Neutral inverse time overcurrent |
| 67P | Phase directional time overcurrent |
| 87L | Line current differential |

### 11.3.2 Miscellaneous Abbreviations

| | |
|---|---|
| 1LG | Single line to ground |
| 2L | Two line or two phase |
| 2LG | Two line or two phase to ground |
| 3LG | Three line or three phase to ground |
| CB | Circuit Breaker |
| CT | Current transformer |
| CTI | Coordination Time Interval |
| CTR | Current transformer ratio |
| CCVT | Capacitor coupled voltage transformer |
| IOC | Instantaneous overcurrent element |
| LL | Line to line or phase to phase |
| LOP | Loss of potential |
| MRCT | Multi-ratio current transformer |
| MTA | Maximum torque angle (for distance relays with mho circle characteristics) |
| PT | Voltage transformer |
| PTR | Voltage transformer ratio |
| SLG | Single line to ground |
| TOC | Inverse time overcurrent element |
| VT | Voltage transformer |
| VTR | Voltage transformer ratio |

| | |
|---|---|
| SIR | Source impedance ratio (positive-sequence source impedance divided by positive-sequence line impedance) |
| POTT | Permissive overreaching transfer trip |
| DTT | Direct transfer trip |

## 11.4 References

### 11.4.1 Industry Standards, Text Books, White Papers and Application Notes

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